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Marginal costs of water savings from cooling system retrofits: a case study for Texas power plants

Aviva Loew, Paulina Jaramillo and Haibo Zhai

Department of Engineering and Public Policy, Carnegie Mellon University, Pittsburgh, PA, USA

E-mail: aloew@andrew.cmu.edu

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Abstract

The water demands of power plant cooling systems may strain water supply and make power generation vulnerable to water scarcity. Cooling systems range in their rates of water use, capital investment, and annual costs. Using Texas as a case study, we examined the cost of retrofitting existing coal and natural gas combined-cycle (NGCC) power plants with alternative cooling systems, either wet recirculating towers or air-cooled condensers for dry cooling. We applied a power plant assessment tool to model existing power plants in terms of their key plant attributes and site-specific meteorological conditions and then estimated operation characteristics of retrofitted plants and retrofit costs. We determined the anticipated annual reductions in water withdrawals and the cost-per-gallon of water saved by retrofits in both deterministic and probabilistic forms. The results demonstrate that replacing once-through cooling at coal-fired power plants with wet recirculating towers has the lowest cost per reduced water withdrawals, on average. The average marginal cost of water withdrawal savings for dry-cooling retrofits at coal-fired plants is approximately 0.68 cents per gallon, while the marginal recirculating retrofit cost is 0.008 cents per gallon. For NGCC plants, the average marginal costs of water withdrawal savings for dry-cooling and recirculating towers are 1.78 and 0.037 cents per gallon, respectively.

Introduction and research objective

The cooling systems of thermoelectric power plants account for over 40% of US water withdrawals, making the power sector reliant on water availability and a potential contributor to water stress [1]. Most of these withdrawals are from surface water, so this large demand makes the power sector vulnerable to surface water shortages. Strategies to mitigate the risk include cooling technologies that are not water withdrawal-intensive.

Population growth, economic development, and warmer temperatures are expected to increase demands for both electricity and water. Droughts exacerbate the strain on electrical utilities when reduced water availability is typically paired with hotter temperatures and higher electricity demand for air conditioning. While power generation may be shifted towards less arid regions in times of severe water shortage, this action stresses the grid, and depending on the scale and degree of drought, may not adequately compensate for generation from plants forced off-line [2]. Indeed, droughts of recent years have threatened power generation throughout the nation [3, 4]. The temperatures of summer 2011, for example, put the vast majority of Texas in a state of 'exceptional drought' and forced at least one power plant to down-scale operations because of water shortages [5].

The cooling system is the largest driver of water withdrawal rates in power plants. Cooling system retrofits may thus serve as a mitigation strategy for power curtailments driven by water constraints and may improve water availability for other sectors. Cooling systems for power plants include once-through systems, recirculating systems (also referred to as cooling towers or wet cooling), and air-cooled condensers (ACC) for dry cooling. Once-through cooling systems operate by continually withdrawing large quantities of water from a nearby source, such as a river or lake, and using this water to absorb heat from exhaust steam exiting the steam turbine in a steam-cycle plant. Recirculating cooling systems operate similarly to once-through systems, but rather than withdrawing and discharging the entirety of the cooling water, the water circulates through cooling towers that lower the water temperature mainly due to evaporation of water in contact with ambient air. Because cooling occurs partly via evaporation, recirculating systems have higher consumptive water use rates than once-through cooling systems; however, because the recirculating systems reuse the water, the overall withdrawal volume is lower, as withdrawals only need to make up for evaporative loss and tower blowdown needed to prevent mineral build-up in the cooling system.

Once-through systems have come under increased regulatory pressure in recent years due to section 316b of the Clean Water Act, intended to protect aquatic organisms and reduce fish impingement at cooling pumps [6]. Facilities with once-through systems may either switch to recirculating systems or employ technologies that prevent fish from entering the water intake facilities. While retrofits to recirculating retrofits would in fact reduce the volumes of water withdrawn, neither of these strategies will completely eliminate the vulnerability of the power sector to climate-induced water availability constraints.

Unlike once-through and recirculating systems, dry-cooling systems condense the exhaust steam with air rather than water. These systems operate by diffusing steam through coiled cables of high surface area and using convection, fans, and sensible heat transfer to condense the steam. The large capital costs and their relatively recent development make dry cooling systems less common in US power plants [7, 8]. Further, the efficiency penalties of dry-cooling retrofits increase the fuel use for a given plant size, which in turn increases the variable operating costs. Dry-cooling systems, however, would significantly reduce water withdrawal rates in power plants.

We selected Texas as a case study to examine changes to cooling technologies and water withdrawals, as the state has significant thermoelectric power capacity, growing demand for electricity, and has in the past experienced drought conditions that have affected power plant operations. In Texas, water withdrawals for thermoelectric power generation in 2010 accounted for 41% of the state total [1]. While 98% of withdrawal volume for cooling systems is discharged back to the hydrological system, power plant operations still require a given water volume being present [1]. Reducing withdrawal rates may thus strengthen the resilience of power plants in low-flow periods, which may increase in the future with climate change [9]. Furthermore, reducing water withdrawal rates may also offer other benefits to the hydrological system. The discharge of cooling water back into the water system is associated with higher temperature effluents, which disrupt aquatic ecosystems [4]. Additionally, the water unavailable between the power plant intake and outtake may make the water unavailable to other critical demands, such as irrigation or municipal supply.

This paper focuses on quantifying the costs of cooling system retrofits to reduce water withdrawals at Texas power plants. Further, while we focused on reducing water withdrawals to mitigate climate-driven risks to the power system, we also estimated changes in consumptive water use (water not returned to a water resource system) that result from cooling system retrofits. While the power generation sector only accounted for 4.2% of Texas consumptive water use in 2010, this volume is nonetheless non-trivial and reduces overall water availability in a drought-stricken state [10].

This is not the first paper to evaluate the water-energy nexus in the state of Texas. Several previous studies have used power plant models to examine water use for new fossil fuel-fired power plants in the context of changing regulatory environments and future power plant fleets [11–13], while other studies have valuated the opportunities for fuel switching or water use fees to mitigate water constraints in the energy sector [14–17]. Some work has also been done to evaluate cooling system technologies in thermal power plants. The Electric Power Research Institute has produced two reports that outlined capital costs and efficiency trade-offs associated with changes in cooling systems [18, 19]. A more recent study by Stillwell *et al* (2013) examined cooling system retrofits in Texas [20]. Specifically, the authors selected a number of plants from different water basins in Texas and estimated the revenue power plant operators could collect if they could sell their water rights leases after cooling system retrofits.

Unlike previous work, this paper contributes to the water-energy-climate literature by explicitly evaluating the costs of deploying water-saving cooling system technologies to mitigate water availability constraints at existing coal and natural gas combined-cycle (NGCC) plants in Texas. We report our results as the marginal cost of avoided water withdrawals (measured as dollars per gallon of water withdrawal avoided). This metric enables comparisons between the different plants as well as against the costs of other water supply strategies. This work differs from previous studies by evaluating power plants individually and estimating the capital, operation and maintenance (O&M), and fuel costs associated with these retrofits, as well as the changes in water withdrawals. Finally, we estimate the annual amount of avoided water withdrawals resulting from these cooling system retrofits.

Data and methods

For this analysis we rely on the Integrated Environmental Control Model (IECM) to model the operations of pulverized coal-fired power plants and NGCC

Table 1. Characteristics of power plant fleet selected for retrofit analysis.

Categories	Number of plants	Percentage of Texas totals: Electricity generation	Percentage of Texas totals: Installed capacity
Total number of plants	52	63.2%	55%
Plant type			
Coal	19	35.0%	24.6%
NGCC	33	28.2%	30.6%
Cooling system			
Once-through	11	14.4%	12.9%
Wet recirculating	41	45.7%	40.2%

plants in Texas. Our final power plant database consists of 19 coal-fired power plants and 33 NGCC power plants. There is also diversity in cooling technologies, with 11 plants using once-through technologies (5 coal plants, and 6 NGCC plants) and 41 using recirculating technologies (14 coal plants, and 27 NGCC plants). Table 1 summarizes the characteristics of these power plants. We note that due to data availability and the capabilities of IECM, our analysis does not include nuclear power plants, combined heat and power systems, and gas-fired plants that use only gas or steam turbines. As a result, our estimates underestimate the amount of water withdrawal reductions that could be achieved if cooling system retrofits occur in all thermal power plants. Nonetheless, the results of our study are significant as the coal and NGCC power plants in our database account for 49 GW, which is roughly 50% of the installed capacity and 60% of generation output in Texas [21]. Furthermore, these 52 plants account for roughly 20% of surface water withdrawals in the state of Texas and 3.7% of consumptive water use [1].

Individual power plant data come from publicly available databases, including the data from EIA Forms 923 and 860. Collected annually, EIA Form 923 focuses on electric power plant operating data and Form 860 includes environmental information on generators [21, 22]. Together, these forms provide details on power plant fuels, nameplate capacity, and cooling technologies. We determined the age of each power plant using the ages of the component generators, by weighting the generator ages according to capacity share of the overall plant. The current age of the power plant determines the project book lifetime of the potential retrofit, which we used to estimate the levelized cost of the retrofit investments. Net annual generation and fuel input, used to calculate net heat rate and net efficiency, came from EIA data. Given the parasitic efficiency loss associated with cooling systems, we needed to determine the gross capacity of plants to model the same plants pre- and post-retrofit. We estimated the gross capacity of the plants in equation (1), by using the gross generation from the Air Markets Program data (which is part of the EPA's Clean Air Markets Division and Continuous Emissions Monitoring Systems database) and the capacity factor (determined from net generation and net capacity from the EIA data). Finally, we relied on the Air Markets Program Data to determine which pollutant abatement technologies are present at given power plants, which affects their operating efficiency before and after cooling system retrofits [23]. All power plant data is for 2012

$$\text{Plant gross capacity (MW)} = \frac{\text{Gross generation (MWh)}}{\text{Capacity factor (\%)} \times 365 \times 24}. \tag{1}$$

Power plant modeling under meteorological uncertainty

In order to model the cooling system retrofits we used IECM, previously developed at Carnegie Mellon University [24, 25]. This model outputs plant performance characteristics and costs for different combinations of power plant technologies and cooling systems. To estimate the cooling system water requirements, IECM incorporates ambient weather data, which we obtained by mapping the power plants in our database to weather stations using Quality Controlled Local Climatological Data from the National Climatic Data Center [26]. The online supplementary information (SI) includes further details on this mapping process.

For the dry-cooling system design, monthly temperature maximums of ambient air were necessary because the warmest anticipated ambient air conditions drive the size and capital cost of the dry-cooling system for a given capacity. Higher temperatures lead to a larger dry-cooling system, because dry cooling relies on the temperature difference between the exhaust steam and the inlet air. In contrast, plant capacity and the steam cycle heat rate are the main drivers of the size of wet recirculating systems, while humidity only affects the operating conditions. Therefore, annual averages for humidity and temperature were suitable to model cooling tower capital costs in IECM [25].

The meteorological conditions under which power plants retrofits would operate are predictable with a limited degree of certainty but nonetheless important to the metrics we are calculating. Future work may incorporate future climate scenarios, but in this paper we will present climate-driven uncertainty by considering recent climate conditions. When examining the annual average air temperatures, annual relative humidities, and average monthly maximums over the past five years for the weather stations linked to selected power plants, we found them to closely follow a normal distribution. Therefore we added

Table 2. Probability distribution functions for NGCC meteorological uncertainty analysis.

Input variables in IECM	Assumed distribution function	Distribution function parameters
Annual average temperature (°F)	Normal	Mean: 69, standard deviation 2.7
Annual average humidity (°F)	Normal	Mean: 62, standard deviation: 8.1
Monthly average maximum (°F)	Normal	Mean: 98, standard deviation: 7.0
Steam-water temperature differential (°F)	Uniform	Min: 20, max: 40

normal distributions to the temperature and humidity inputs within IECM. In the case of coal plants, we assigned the distribution of the meteorological data for the closest station to each plant. The SI includes these distributions. For NGCC plants, we modeled our fleet based on sample plants (as described below), so we used average values from the stations closest to NGCC plants. Finally, we also include uncertainty on the steam-water temperature differential, as the volume withdrawn by once-through systems is highly dependent on the temperature difference between the intake stream and the steam entering the condenser. The closer the temperatures of intake water and steam, the more water must be withdrawn to adequately cool the steam. Consequently, we added a uniform distribution to the IECM temperature differential for once-through systems, from 20 to 40 °F [25].

For coal plants, we were able to model each individual plant in IECM. To do so, we identified the predominant coal type at each plant and modeled them accordingly. The SI lists these plant-specific coal designations. We assumed that sub-bituminous plants used Wyoming Powder River Basin coal in the IECM fuel database and that lignite plants used North Dakota lignite. The input parameters to IECM included gross capacity, capacity factor, pollution abatement measures, ambient temperature, and relative humidity. We further adjusted the steam cycle heat rate so that net efficiency of the IECM model matched that in the power plant operating data from EIA. When modeling the same plant with a dry-cooling system, we scaled the adjusted steam-cycle heat rate by a correction factor to adjust for the higher heat rate in a plant with dry cooling, since there is greater backpressure coming from the condenser [18]. We determined the correction factor by the percentage change in baseline steam cycle heat rate when transitioning to a dry-cooling system for sample plants with default settings, such as inlet steam temperature, turbine back pressure, and auxiliary heat exchange load, in IECM. We also estimated the efficiency penalty and annual power use for dry-cooling systems based on the annual average air temperature, as discussed in detail in the SI.

Unlike coal plants, we were unable to directly model individual NGCC plants from our database in IECM, as IECM includes a discrete set of NGCC plant sizes based on the number of GE 7FA or 7FB gas turbines in a plant, which can range between 1 and 5. Thus, in order to model the existing NGCC plants in Texas, we modeled 10 plants in IECM with different combinations of turbines and cooling system: 5 plants with increasing number of turbines, ranging from about 275 to 1375 MW, having either a once-through or recirculating cooling system. Finally we modeled 5 NGCC plants with air-cooled condensing system for our retrofit scenarios. For these NGCC plants with dry cooling, we selected the monthly average maximum temperature (the highest monthly average of daily maximums over a one year period), the annual average temperature, and the annual relative humidity summarized in table 2, representing averages over the past five years from weather stations closest to selected plants in our database. The simulations of the sample NGCC plants yielded relationships between gross capacity and capital costs of the cooling systems as well as the efficiency penalties when switching between systems. We also modeled the water withdrawal and consumption rates in relation to the gross capacity, and used them in conjunction with capacity factor and net generation data to model total water use for each NGCC plant in our Texas database. The parameters to model individual NGCC plants in our fleet from the sample NGCC plants are in the SI. An additional adjustment was necessary for the water use of three of the combined-cycle plants in our database. These plants are older, so the turbines operate at very low efficiencies, 34%–39%, much less than the IECM default of 50% efficiency. For these plants, we adjusted the withdrawal and consumption rates with a correction factor derived from the ratio of the actual heat rate of each plant to the default heat rate in IECM.

Cost assessment method

IECM outputs water withdrawal and consumption rates in tons per hour. We translated these values into gallons per kWh using the density of water and the net size of the plant. We calculated reductions in water withdrawals (and consumption) on an annual basis by multiplying these withdrawal rates by the net annual generation. Since generation at a given plant varies from year to year, we averaged capacity factors over the past five years and used the nameplate capacity to arrive at an estimate of annual generation at each plant. The difference between water volumes of the existing system and the retrofitted system yielded water use averted by undergoing the retrofit.

IECM reports total capital costs for cooling systems. To calculate the annualized cost, we annualized the capital cost with a capital recovery factor based on the remaining lifespan of the plant and a discount rate, using equation (2):

$$\text{Capital recovery factor (CRF)} = \left(\frac{i(1+i)^n}{[(1+i)^n]-1}\right), \qquad (2)$$

where n is the remaining lifespan of the plant, and i is the discount rate. Note that we assumed the life of a power plant is 60 years, so the remaining lifespan of the plant is the difference between 60 and the determined age of the plant, derived from the capacity-weighted ages of the generators from EIA Form 860. The SI includes the estimated ages for the power plants in the database.

In addition to capital costs, IECM provides fixed O&M costs associated with the cooling systems of each plant. Once-through systems are assumed to have no significant fixed O&M costs since the cooling pump apparatus requires negligible maintenance [24]. In contrast, recirculating towers and ACC incur significant annual fixed O&M costs. Our cost estimates of the cooling system retrofits include the change in fixed O&M costs. As before, we are able to obtain individual cost penalties from IECM for each coal plant in the database. For NGCC plants, the fixed O&M costs of cooling systems are estimated as an exponential function of plant capacity, based on the sample plants simulated in IECM.

We also incorporated additional annual fuel costs associated with the efficiency penalty of retrofits. We calculated fuel costs by examining the change in efficiency between the current and retrofitted plant, converting both values to a heat rate, and looking at the change in heat rate along with fuel prices. Table 3 summarizes IECM outputs. A full table with detailed information about each plant in the database is available in the SI.

While this paper primarily focuses on dry-cooling retrofits, there are 11 plants in the database that have once-through systems and could reduce their withdrawal rates by switching only to a recirculating system. For completeness, we include this retrofit option in our analysis.

To normalize the annualized capital costs of the cooling system retrofits, additional fuel costs from the efficiency change, and additional O&M costs, we divided by annual net electricity generation of a retrofitted plant. This yields a cost per kilowatt-hour. Dividing this value by the reduction in withdrawals per kilowatt-hour provides a cost per gallon of water withdrawal reduction, which we define as the marginal costs of avoided water withdrawals (MCAWW). Equation (3) describes this normalization

Table 3. Summary of IECM outputs for our selected coal and NGCC power plants in Texas (once-through systems represent existing plants, dry cooling systems represent retrofitted plants, and recirculating systems combine values for both existing plants and retrofitted plants). The results for each power plant include a probability distribution based on the meteorological uncertainty. The values in this table represent the ranges in mean values for all the power plants in the database. The SI includes the distributions for individual power plants.

Performance and costs	Coal	NGCC
Withdrawal rates (gal kWh^{-1})		
Once-through	21–28	5.4–8.8
Recirculating	0.37–1.0	0.18–0.39
Dry cooling	0.06–0.17	0
Consumption rates (gal kWh^{-1})		
Once-through	0.52	0.12
Recirculating	0.24–0.70	0.13–0.25
Dry cooling	0–0.09	0
Relative decrease in net plant efficiency (%)		
Once-through to dry cooling	3–4	2–3
Recirculating to dry cooling	2–4	1–2
Once-through to recirculating	0.3–1	<1
Capital costs ($M)		
Dry cooling	129–722	41–200
Recirculating	95–159	18–57
Annual operational costs ($M)		
Dry cooling	3.0–12.0	1.6–4.0
Recirculating	1.6–3.9	0.77–1.8

where CRF is the capital recovery factor from equation (2); ΔO&M is the change in annual fixed O&M costs resulting from the cooling system retrofit; ΔHeat rate is the change in heat rate resulting from the cooling system retrofit (in BTU kWh^{-1}); fuel costs are in $/BTU; annual generation is based on the 5 year average capacity factor of the plants; and ΔWater use rate is the change in water withdrawal rate resulting from the cooling system retrofits (derived from IECM outputs).

Uncertainty analysis on financial parameters

IECM outputs include probability distributions for water withdrawal and consumption, generation, efficiency, fixed O&M costs, and capital costs of cooling system retrofits for each power plant based on the meteorological uncertainty previously described. These distributions serve as inputs to equation (3). In addition to this uncertainty, this analysis incorporates

$$\text{MCAWW} = \frac{\dfrac{[(\text{CRF}^*\text{Capital costs})+(\Delta\text{O\&M}) + (\Delta\text{Heat rate}^*\text{Fuel costs})]}{\text{Annual generation}}}{\Delta\text{Water use rate}}, \qquad (3)$$

Table 4. Probability distribution functions for uncertainty analysis.

Input variables in IECM and cost calculations	Assumed distribution function	Distribution function parameters
Discount rate (%)	Triangular	Min: 5, max: 15, MLV: 7
Coal price ($/MMBtu) [27]	Uniform	Min: 1, max: 2
Gas price ($/MMBtu) [27]	Uniform	Min: 2.8, max: 7.8

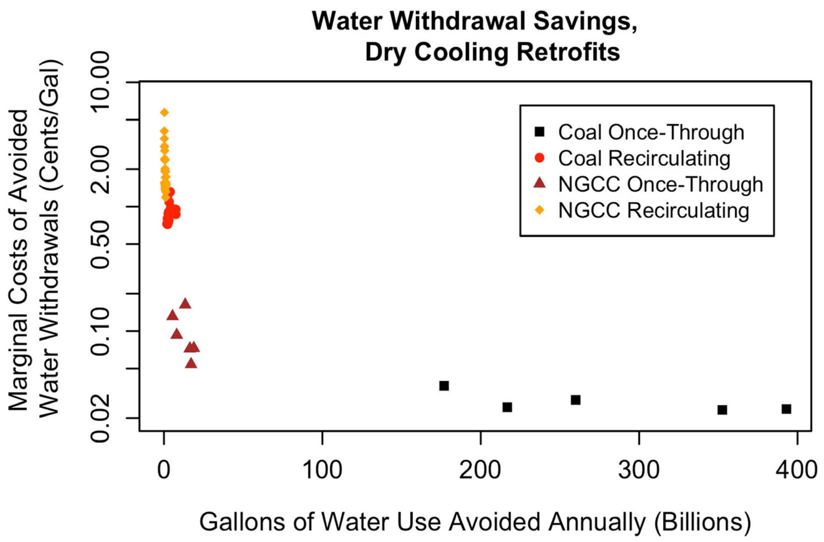

Figure 1. Marginal costs of avoided water withdrawals with dry-cooling retrofits for coal and NGCC power plants in Texas. The data labels represent the cooling system of plants prior to the retrofit.

uncertainty in discount rates and fuel prices. Table 4 summarizes the probability functions used to model non-meteorological uncertainty in equation (3).

Results and analysis

Using the data previously described, we ran a Monte Carlo simulation with 1000 iterations to determine the 95th percentile confidence interval for the reduction of annual water withdrawals and the marginal costs of avoided water withdrawals ($ per gallon) for each power plant. Figure 1 displays the reductions in annual water withdrawals that result from dry cooling retrofits at coal and NGCC plants. For both coal and NGCC plants, retrofitting those plants that currently have once-through systems to dry-cooling retrofits have the lowest cost per gallon of water saved and achieve the greatest water withdrawal savings per retrofit. Changing from recirculating wet towers to dry cooling accounts for the cluster of plants near the y-axis: the retrofit costs per gallon of water withdrawal saved are relatively high, and these retrofits save smaller volumes of water. The age of plants and capacity factors contribute to the difference in cost per gallon among these recirculating plants. Low capacity factors reduce potential water savings. For plants approaching the end of their projected lifespan, the higher capital recovery factor further raises the annualized and levelized retrofit cost.

Figures 2(a)–(d) show plants that currently have recirculating and once-through cooling systems, respectively, with the dots representing mean values for individual plants. Figure 2 also includes the uncertainty in the cost results. The large potential withdrawal savings of once-through systems undergoing retrofits contribute to their lower marginal costs of avoided water withdrawals, when compared to recirculating systems.

Comparing figures 2(a)–(d) shows that retrofitting coal plants with dry-cooling systems results in larger reduction in water withdrawals per plant than retrofitting NGCC plants with dry-cooling systems, because the cooling system of NGCC plants only serves the steam cycle and in turn has lower cooling loads. As a result of this difference, overall retrofit costs for NGCC plants are lower than for the coal plants, but so are the water savings, which lead to NGCC plants having higher marginal costs of avoided water withdrawals than the coal plants.

While dry cooling systems offer significant reductions in water withdrawals, some of these same reductions could be achieved by retrofitting once-through cooling systems with recirculating systems. Figure 3 shows the reductions in water withdrawals and marginal costs of avoided water withdrawals associated with these retrofits and confirms that retrofitting once-through cooling plants with recirculating systems results in water withdrawal reductions similar to retrofitting the plants with dry-cooling systems, at a lower cost.

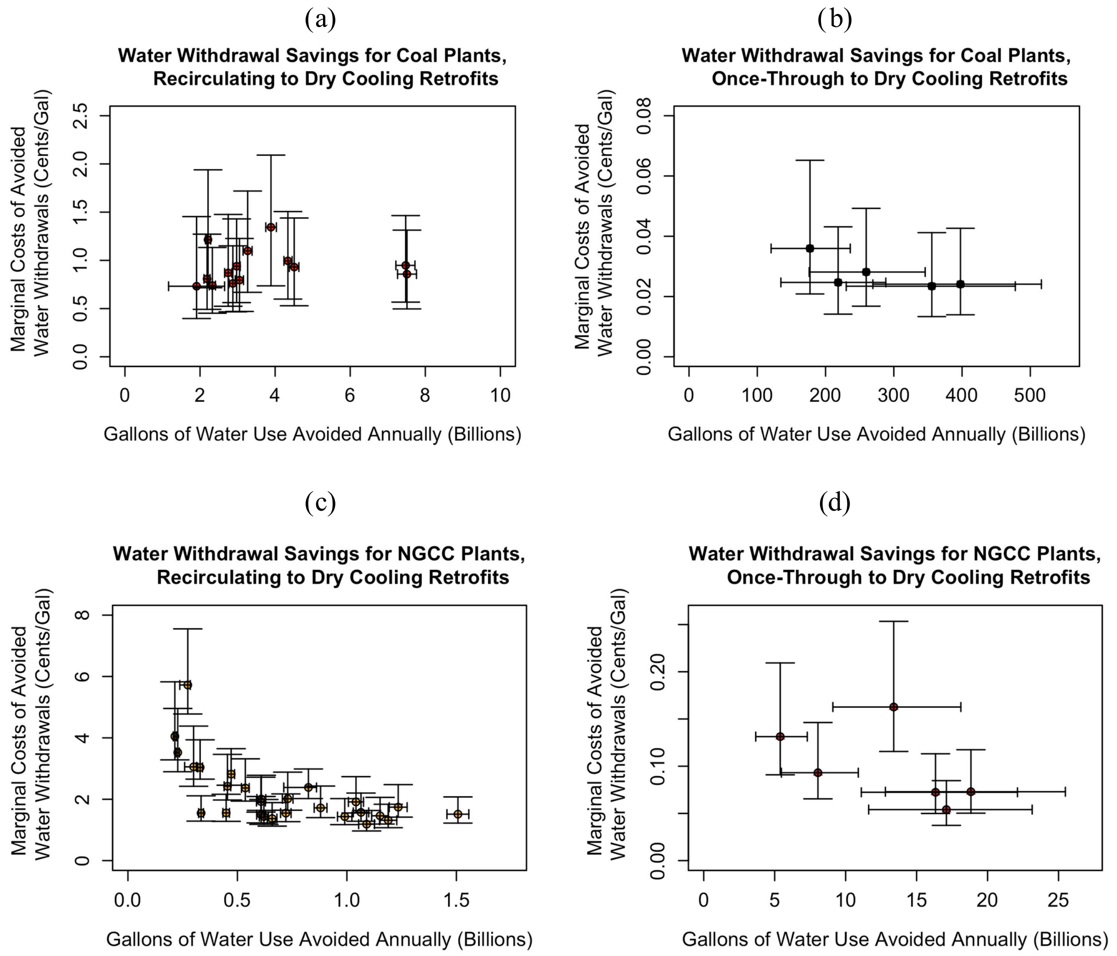

Figure 2. Marginal costs of avoided water withdrawals with dry-cooling retrofits for coal and NGCC power plants in Texas. (a) Coal plants with recirculating systems. (b) Coal plants with once-through systems. (c) NGCC plants with recirculating systems. (d) NGCC plants with once-through systems.

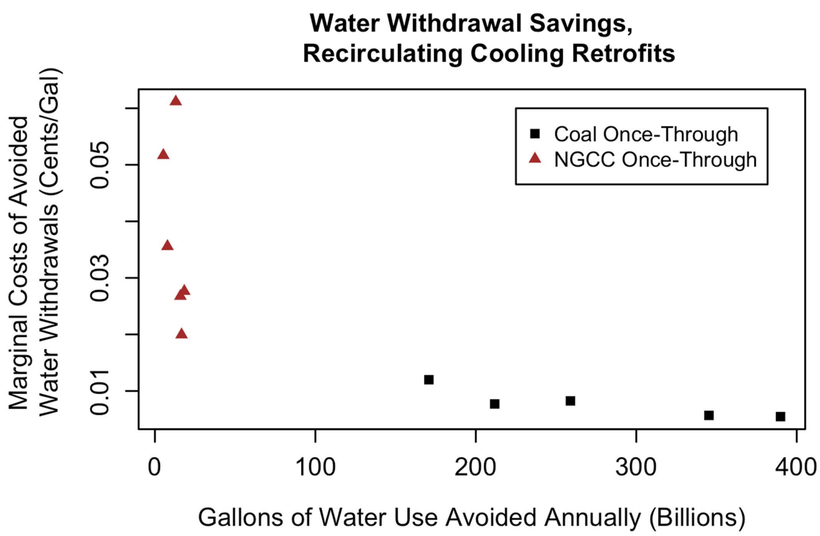

Figure 3. Marginal costs of avoided water withdrawal from switching once-through coal and NGCC power plants to recirculating cooling systems.

While this paper focuses on reductions in water withdrawals as a mechanism to reduce water-induced risks at power plants, cooling system retrofits may also affect consumptive water use at power plants. As previously mentioned, retrofitting once-through cooling systems with recirculating systems provides relatively

Table 5. Fleet total change in consumptive water use (mean values) from retrofits for coal and NGCC power plants in Texas.

Fuel type	Retrofit transition	# of plants	Total consumption difference annually (Gallons)
Coal	Once-through to dry-cooling	5	29.6 billion
	Once-through to recirculating	5	−3.04 billion
	Recirculating to dry-cooling	14	38.6 billion
NGCC	Once-through to dry-cooling	6	1.41 billion
	Once-through to recirculating	6	−0.46 billion
	Recirculating to dry-cooling	27	13.9 billion

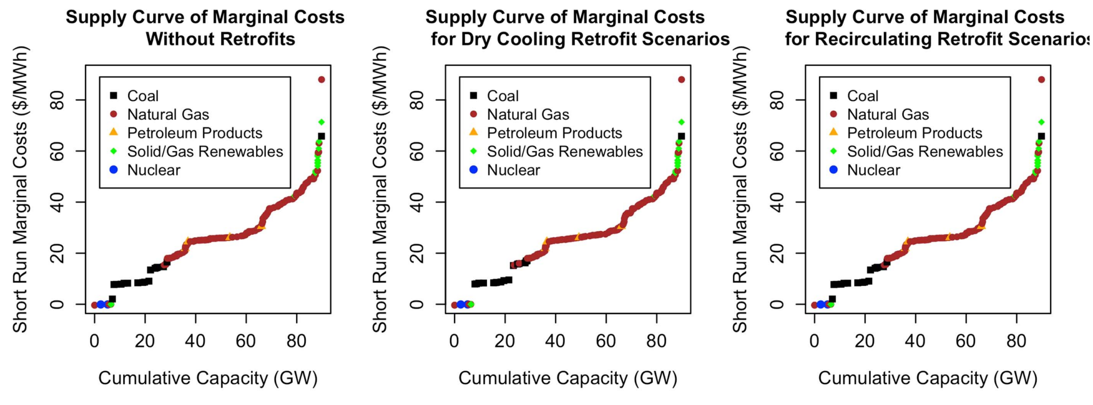

Figure 4. Dispatch (supply) curves within ERCOT. (A) Without retrofits. (B) For all plants within our dataset transitioning to dry cooling systems. (C) For all plants with once-through systems in our dataset transitioning to recirculating systems.

low cost reductions in water withdrawals from power plants. However, recirculating systems have higher consumptive water use than once-through systems. Table 5 includes the change in consumptive water use from the different retrofit options. IECM does not report consumptive water use for once-through systems so water intensities for these plants came from the literature [10, 28]. There are negative changes in consumptive water use in retrofits to recirculating systems because these retrofits result in increased consumptive water use. However, the reductions in withdrawal are approximately 100–200 times more than the increases in consumption.

We also considered how retrofits might alter the plant scheduling during dispatch in ERCOT. Figure 4 shows the dispatch curves, based on the marginal costs of generation for each plant. The SI includes details on the marginal cost calculations. We run three fleets in 2012: the baseline fleet, one with the plants in our dataset all undergoing dry cooling retrofits, and one with the once-through plants in our dataset all undergoing recirculating retrofits. The dry cooling retrofit scenario shows a slight reordering of plants in the dispatch curve, with some coal plants falling behind NGCC plants in scheduling. While there are many other factors that affect the annual capacity factors of power plants (including ramping constraints, transmission constraints, renewable penetration, etc), a shift in the dispatch order could result in some plants being operated more or less often than in the past. The marginal costs of avoided water withdrawals and the annual avoided volumes reported in the previous figures are based on the 5 year average capacity factor of the power plants in our database. A drastic change in capacity factors in the future would affect these estimates. In particular, a reduction in capacity factor would increase the levelized capital costs of the retrofits. The dispatch curves in figure 4 suggest, however, that the changes in marginal costs of generation that result from decreased efficiency associated with the cooling system retrofits are not significant enough to drastically change the dispatch order. As a result, all else being equal, it is unlikely that the cooling system retrofits would drastically affect the capacity factors of the plants. This is not to say that individual power plants in our database will operate at the same capacity factor for the remainder of their life. Changes in capacity factor may occur, for example, because of a significant increase in natural gas prices or expanded wind power capacity. Accounting for such changes in capacity factors is beyond the scope of this study. We note, however, that the individual decisions to retrofit the cooling systems in our power plants should account for expectations about future capacity factors. If, for example, there are expectations that one of the plants in our database will have lower capacity factors because of wind, then such plant may not be a suitable candidate for a cooling system retrofit. Our results demonstrate, however, that cooling system retrofits could enable power plants to maintain their operating capacities while reducing water withdrawals.

Discussion

Retrofitting all coal plants with dry-cooling systems results in a substantial reduction in water withdrawals at a cost of roughly 0.68 cent per gallon of water (withdrawal) saved. The reductions in water withdrawals that result from retrofitting the cooling systems at NGCC plants are smaller but significant nonetheless. Once-through systems retrofitting to dry-cooling systems achieve significantly more water savings per monetary investment than recirculating systems making the same transition. Table 6 summarizes the fleet averages of mean annual withdrawal volumes saved at each plant undergoing the designated retrofits, as well as the average gallons of water saved per kWh of generation, retrofit cost per kWh, and cost per gallon saved, for each type of cooling retrofit. A private-sector utility may be more concerned with the cost per kWh, whereas a public-sector decision-maker may be more interested in the cost per gallon.

The data confirm that retrofitting once-through systems to recirculating systems at coal plants provides the lowest cost per withdrawal savings. However, while transitioning from once-through systems to recirculating systems results in reductions in withdrawal volumes that far exceed the associated increases in consumptive volume, the tradeoff exists.

Table 7 includes total reductions in water withdrawals associated with retrofitting all plants in the database as a fraction of withdrawals in Texas, based on the latest estimates from USGS [1]. Reductions in water withdrawals from plants with once-through cooling systems account for over 15% of the state water withdrawals, meriting particular attention. We also compared the cooling system retrofits for this fleet of Texas power plants with other water conservation and water supply projects proposed by the Texas Water Development Board (TWDB), as detailed in the SI. Once-through systems achieve the same annual cost-per-gallon as the lowest cost-per-gallon TWDB proposals, largely municipal conservation measures. Dry-cooling retrofits for recirculating systems rank alongside projects such as groundwater expansion and brackish water desalination [29].

A study by Sanders *et al* examined water use fees as a water management strategy in Texas. This water fee would be akin to a carbon tax and would thus affect the dispatch order of power plants, which in turn would affect the costs of meeting electricity demand. The authors then defined a cost-effectiveness of 'supplying water' through changes in dispatch order as the change in marginal cost of power generation divided by the amount of water saved. Using different scenarios, the authors estimated a cost effectiveness ranging between \$0.17 and \$0.49 per gallon of water withdrawal reduction through changes in the dispatch order [17]. Our marginal costs of avoided water withdrawals are markedly lower for cooling system retrofits, highlighting that technological solutions to water use in the power sector merit consideration in long-term water management plans.

While we did not model nuclear power plants in this analysis, they also have significant water use profiles. Texas has two operational nuclear power plants, with one using a once-through cooling system and the other using a recirculating system [21]. The water withdrawal and consumption intensities of nuclear plants exceed those of coal-fired plants, and nuclear power accounts for approximately 10% of generation in Texas [10, 28]. Therefore, we expect that retrofits at a nuclear plant with once-through cooling would also achieve notable water withdrawal reductions.

As noted, our analysis presents an exploratory analysis of cooling system retrofit prioritization, rather than a precisely prescriptive conclusion. The water use data for power plants is limited, and future meteorological conditions and their effects on water use are inherently uncertain. Power demand may also increase, and the distribution of operating hours at individual plants may change. We did not find that the efficiency penalty of retrofits dramatically changed the marginal cost curve for our plants, so we would not expect the dispatch schedule to change on account of cooling technology retrofits. Nonetheless, these changes could affect the exact value of the marginal costs of avoided water withdrawals presented in this paper. If more specific data for expected future conditions at each power plant become available, the modeling framework in this paper could be used to produce more context-specific results.

While complete power plant shutdowns induced by water-shortage are uncommon, even in the case of drought, increased water demand from other sectors and extreme climate conditions may exacerbate scarcity in water supply and thus increase the risks to reliable power provision. Thus cooling system retrofits may be a viable climate-adaptation strategy for some of the power plants in our database. However, several power plants evaluated in this study are towards the ends of their lifespans, where a retrofit is less appropriate than a retirement. Retiring these old and low-efficiency plants along with increasing the capacity factors at existing NGCC plants with recirculating cooling systems may be a more effective mechanism to reduce water use in the power system. Additionally, a decision-maker will need to consider water stress levels at specific locations, as higher cost-per-gallon retrofits may still be desirable in regions routinely experiencing severe water shortage.

Table 6. Fleet averages of withdrawal changes and cost from retrofits for coal and NGCC power plants in Texas.

Fuel type	Retrofit transition	# of plants	Average withdrawal saved annually per plant (Gallons)	Average withdrawal reduction (gal kWh^{-1})	Average cost to plant operator (cents kWh^{-1})	Average Marginal cost of avoided water withdrawals (cents gal^{-1})
Coal	Once-through to dry-cooling	5	280 billion	24.5	0.67	0.027
	Once-through to recirculating	5	275 billion	24.1	0.12	0.008
	Recirculating to dry-cooling	14	3.67 billion	0.69	0.63	0.92
NGCC	Once-through to dry-cooling	6	13.3 billion	7.18	0.75	0.098
	Once-through to recirculating	6	12.8 billion	6.92	0.27	0.037
	Recirculating to dry-cooling	27	0.70 billion	0.27	0.60	2.2

Table 7. Fleet total reductions in water withdrawals (mean values) from retrofits for coal and NGCC power plants in Texas, as a percentage of statewide withdrawal.

Fuel type	Retrofit transition	# of plants	Total withdrawal saved annually (Gallons)	As percentage of total freshwater withdrawals in Texas[a]
Coal	Once-through to dry-cooling	5	1399 billion	16.2%
	Once-through to recirculating	5	1376 billion	15.9%
	Recirculating to dry-cooling	14	51.3 billion	0.59%
NGCC	Once-through to dry-cooling	6	79.6 billion	0.92%
	Once-through to recirculating	6	77.2 billion	0.89%
	Recirculating to dry-cooling	33	19.1 billion	0.22%

[a] The total freshwater withdrawal volume reported for Texas in 2005 was 26 500 000 acre-feet, or 8635 billion gallons [1].

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